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ELECTRONIC DELIVERY

California Energy Commission
Docket Office
Attn: Docket No. 04-IEP-1K
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

Re: Comments of Pacific Gas and Electric Company

Pacific Gas and Electric Company (PG&E) respectfully submits the following comments to the Committee Draft Report of the 2005 Integrated Energy Policy Report.

Thank you for considering our comments. Please feel free to call me at (415) 973-6463 if you have any questions about this matter.

Sincerely,

Les Guliasi

LGG

Enclosure

PACIFIC GAS AND ELECTRIC COMPANY'S
COMMENTS ON THE CALIFORNIA ENERGY COMMISSION'S
2005 INTEGRATED ENERGY POLICY REPORT
COMMITTEE DRAFT REPORT
October 14, 2005

Pacific Gas and Electric Company is pleased to provide the California Energy Commission (CEC) with comments on the 2005 Integrated Energy Policy Report: Committee Draft Report ("Draft Report"). We look forward to the final Report and its companion reports – the Strategic Transmission Investment Plan and the transmittal report to the California Public Utilities Commission (CPUC) – currently under development by the CEC. Overall, PG&E applauds the CEC for producing a comprehensive portrayal of the state's energy situation and a roadmap for future energy policy for infrastructure investment, resource development, and increasing reliability in the California energy market.

The Draft Report surveys a broad expanse of energy topics in its ten chapters. The underlying staff analysis and stakeholder workshops provided a solid foundation for the Committee to draw upon for its findings, conclusions, and policy recommendations. In these comments PG&E has chosen to highlight for the Commission the areas in which PG&E has concerns about the conclusions drawn and recommendations made by the Committee, and, in particular, areas for which PG&E is requesting specific changes to be made in the final Report.

After a few general observations, we offer comments in the areas of resource procurement; distributed generation and combined heat and power; nuclear power; and natural gas price forecasts, where we disagree with the report or request that the Committee consider changes. In addition, PG&E offers comments on the proposed greenhouse gas standard for procurement; transmission grid expansion, including comments on the Strategic Transmission Investment Plan; and a response to Commissioner Geesman's question regarding the TransBay Cable Project.

GENERAL OBSERVATIONS

The Cost Impact of Policy Initiatives on Customer Rates

The Draft Report notes in several places that California is the sixth largest economy in the world, and that a reliable energy supply is vital in order for California to maintain its economic competitiveness. However, the Draft Report could be improved by a broader examination of how the costs of various policy initiatives might affect customer rates.

According to the Staff Report California and Western Electricity Supply Outlook, July 2005 (Report CEC-700-2005-019), California's average retail electricity prices are the highest in the Western United States. Further, California's electricity rates will likely remain high due to the cost of DWR-contracted electricity supplies, bond payments to recoup the cost of power in 2000-2001, and the cost of new requirements including renewable resource procurement and infrastructure investments such as advanced metering.

Cost/benefit tradeoffs are an important component of many of the policies the CEC discusses in its Draft Report. For example, the CEC encourages accelerated retirement or repowering of aging power plants by 2012 without offering an estimate of the cost of this initiative. It supports increased investment in Distributed Generation (DG) and Cogeneration or Combined Heat and Power (CHP) without adequate mention of fundamental underlying wide range of efficiencies of these types of technologies from cost-effective to wasteful of energy. PG&E believes that policy tradeoffs in the real world are tempered and deepened by a complete consideration of the cost impact, and that these tradeoffs should be examined in general policy documents such as the IEPR, as well as in proceedings such as CPUC rulemakings and investigations. The CEC staff has the analytical talent to improve the state's understanding of these economic choices.

PG&E recommends in future IEPR proceedings that the CEC provide cost estimates for each of the initiatives it proposes, so that the underlying record and public discussion of the Energy Report and its policy initiatives may be fully informed.

Intra-regional and Inter-regional Considerations

The Committee Draft Report is inconsistent in its treatment of the interdependent nature of California in the larger Western energy market. The CEC has a proud record and a long-standing tradition of taking a leadership position in important Western regional activities, such as the Western Governor's Association and in WREGIS. Indeed, the CEC reflects this regional, even international, outlook in its chapter on energy issues between the state and Baja California.

Yet, in discussing California resource procurement and transmission issues, the Draft Report often speaks in a parochial manner. While the document presents an excellent discussion of California energy requirements and resources, it does not adequately consider the relationship of California to Western energy markets. In both electricity and natural gas, California is interconnected with a greater regional energy system that spans the Western United States, Canada, and Mexico. While California must ensure that it has sufficient energy resource to meet its own requirements and avoid a repeat of the electricity market meltdown that occurred in 2000-2001, the Draft Report must recognize that the economics and reliability of energy are inextricably linked in the Western energy markets and cannot be isolated from an analysis of Western markets. California should be able to realize better energy reliability, supply adequacy, efficiency, and lower costs if it properly plans in a regional context.

This regional perspective has been acknowledged and endorsed by Governor Schwarzenegger and his administration. PG&E encourages the CEC, when recommending energy policy, to ensure that the impacts and costs of proposed recommendations be considered in the broader western regional context.

Finally, PG&E notes the Draft Report discusses the state's energy situation as a whole, but does not differentiate between intra-zonal differences within the state. (PG&E notes that staff did an excellent job of presenting intra-zonal differences in the companion reports.) It is important to differentiate between regions, as this may affect state policies or actions. One example of an important intra-regional difference is local resource supply sufficiency. While statewide conclusions regarding resource sufficiency provide an aggregate picture of the current energy situation, Southern California has far more urgent requirements for additional electric generating capacity than northern California. Any specific policies designed to address supply adequacy should reflect this fact.

PROCUREMENT POLICY (Chapter 3)

The Draft Report's Executive Summary conveys the sense that utility procurement is proceeding at an alarmingly slow pace. While this may be the case elsewhere in the US, it is not the case in California. PG&E emphatically disagrees with this perspective and, to the contrary, believes that, at least for its service territory, much progress is being made.

The Draft Report also does not acknowledge the great strides that have been made by the investor-owned utilities in planning for and procuring resources during the past three years, since the IOUs returned to active portfolio management and procurement. The Draft Report depicts a world where the energy infrastructure has been willfully neglected for years by the utilities, and erroneously contends that investor-owned utilities are only investing in short-term resources to meet minimal requirements. This is simply not an accurate or fair representation of current utility procurement practices and utility investment.

PG&E has gone far beyond only short-term investments. It was only in 2003 that utilities were allowed to procure generation resources again, and since that time PG&E has undertaken the following procurement activities:

- Competitive Solicitations - PG&E has issued eight RFOs for near- and multi-year term procurement, two RFOs for long-term renewable resource contracts, and is soliciting for up to 2200 MW of new generation through its long-term RFO issued in 2005.

- Long-Term Contracts - PG&E has contracted for over 1500 MW of resources for contract terms of five years or greater.

- Power Plant Development - PG&E has filed an application with the CPUC to acquire ownership and complete construction of Contra Costa 8, a 530 MW high-efficiency combined cycle unit on an existing site.

- Renewable Generation - PG&E has executed 14 long-term contracts for 450 MW of renewable generation, and is currently conducting a solicitation for additional long-term contracts. PG&E notes that it has a fully developed renewable resource plan that the CEC staff called plausible (See, Investor-Owned Utility Resource Plan Summary Assessment, Staff Report, CEC-700-2005-014, June, 2005, p.53) and is aggressively canvassing the market to ensure it achieves the plan goals.

- Electric Transmission – PG&E has invested, and continues to invest in its infrastructure in an effort to meet reliability needs, growth demands, and to proactively address its aging infrastructure.

PG&E agrees that challenges remain in developing the rules for the state's electricity market, and that these uncertainties still slow investment. Yet, the progress that has been made toward getting new projects started should be acknowledged in the final Report.

DISTRIBUTED GENERATION AND COMBINED HEAT AND POWER (Chapter 4)

The Draft Report proposes that, given the energy efficiency of Combined Heat and Power (CHP), and the positive characteristics of Distributed Generation (DG), such resources should be given a place in the loading order ahead of conventional resources. PG&E disagrees with this proposal, as detailed below.

Distributed Generation

The terms "DG" and "CHP" encompass a very broad range of facilities with varying levels of efficiency, air emissions and other environmental impacts, and system impacts, from small residential PV systems to large QF wholesale cogeneration plants. As such, policies should be developed with a careful consideration of the very different forms of DG and CHP.

PG&E recommends that the final Report include a clear definition of distributed generation, and recommends the following:

> Distributed generation is electricity produced on a customer site from generators under 10 MW in size that are interconnected to the utility distribution system and that are designed predominantly to serve load at the customer site or over the fence to one or two adjacent customers.

Some forms of DG are energy efficient, some use alternative energy sources, and some forms of DG are less efficient and pollute far more than new natural-gas fired power plants. Providing subsidies to the latter group does not advance any identified state goal: any subsidies for the former groups should be provided only if they meet an identified state energy goal, are designed in a manner to make best use of other ratepayers' funds, and fit within an identified overall budget for such incentives. In the CPUC's DG OII proceeding, tools to perform such cost benefit analysis are being developed, and a recent draft decision in this proceeding recommends specific tests to distinguish the varying values of such projects. (See R.04-03-017, Interim Opinion Adopting Cost-Benefit Methodology for Distributed Generation, September 6, 2005)

On page 67 the Draft Report recommends that "California should require utilities to design and construct distribution systems that are more DG and CHP compatible." This recommendation puts the cart before the horse, and fails to recognize that the CPUC is in the process of defining the appropriate tests to determine the value of DG and CHP. Any recommendation for transmission and distribution system design and construction should also include a requirement that the costs of upgrades be balanced with the value of DG and CHP.

The CPUC's Draft Decision in the DG OIR has determined that the record in the proceeding designed to examine the value of DG for transmission and distribution systems will not sustain a change from a recent decision that identified the narrow circumstances under which such value exists. (See R.04-03-017 September 6 Interim Opinion pages 21-22, citing D.03-02-068.) The recommendation for transmission and distribution "DG compatibility" should be eliminated or at least refined to be consistent with the R.04-03-017 Interim Opinion and any subsequent Decision. The Draft Report should not recommend additional distribution system accommodations for DG at this time, accommodations which could lead to substantial costs to customers and may not have the intended benefit. It is premature to make such a recommendation without first examining whether the DG cost benefit methodology, expected to be voted on by the Commission very soon, can be used as a tool to promote the integration the technologies where they are most beneficial to society, participating, and non-participating customers.

Cogeneration or Combined Heat and Power

CHP facilities, as well, come in many sizes and in varying degrees of efficiency and environmental impact. Some are small DG facilities, and others are large plants that interconnect at transmission level voltages. Some are thermally matched resources that are predominantly self-generation, and some are designed to sell energy primarily at the wholesale level to utilities.

PG&E agrees that it may be appropriate to encourage the addition of a truly efficient future CHP resource, if the benefits and cost show it to be valuable to both society at large and to non-participating ratepayers, and if the utility system can accommodate its operating characteristics.

While a new CHP investment might well hold efficiency advantages for the state, the majority of old CHP investment is far from virtuous and does not deserve any special recognition. Most of the cogenerators operating in the state today are well into their second decade of operation. They tend to have much lower overall efficiency than a modern combined cycle power plant, and higher emissions as well. Many were sized such that the steam use is a very small fraction of their energy production. Old, dirty, inefficient cogeneration plants do not deserve preferred status in the loading order or continued ratepayer subsidies. There should be no loading order advantages for current cogenerators seeking new contracts with the IOUs.

Additionally, these resources are not as dedicated to the reliability of the grid as other sources. The Committee Draft Report, at page 64, states, "First, California has more than 9,000 MW of CHP across the state. With statewide generation capacity at approximately 60,000 MW, CHP is a key component of the grid, representing approximately 17% of generation, and is often used to preserve the reliability of the grid." The draft report also claims a realistic goal for another 5,400 MW of CHP by 2020. Yet, three paragraphs later, on p. 65, the Draft Report states, "CHP owners choose to operate their businesses and produce electricity only when the economics are favorable. CHP policy therefore cannot be similar to policies developed for more traditional customer generators or power plants." Nonetheless, the Draft Report concludes that this is "not problematic" as IOUs have diverse portfolios.

The conclusion that utilities can accommodate over 20 percent of capacity from resources that deliver power only "as-economic" is not consistent with the natural reaction that these entities would exhibit given the market drivers, and is not consistent with the CEC's earlier conclusions on these entities acting in economic interests. Given the state's load profile and the intermittent nature of many renewable resources which utilities will procure to meet the RPS goals, utilities require flexible and dispatchable resources rather than must-take and unreliable capacity. Increasing the level of must-operate CHP resources, or worse yet, CHP resources that only operate when it is economically beneficial for the operator, will undermine reliability of the electric system rather than increase it. Further, if utilities are forced to procure more resources to accommodate as-available CHP generation, it would increase costs and reduce overall efficiency.

Cogeneration is an old, well understood technology that has been actively utilized in California for over 50 years and in Europe longer than that. Cogeneration has the potential to be efficient by the sequential withdrawal of electric and thermal energy released by burning fuel and/or by extracting useful energy from some part of the heat exhausted from power generation equipment. When these benefits were inherently obvious, owners of industrial facilities – such as C&H sugar – installed cogeneration equipment in the early 1950s, without government incentives, to do both: generate power for their operational needs and heat ("cook sugar") for their industrial processes.

The introduction of PURPA and its implementation in California in the 1980s through the standard offer QF contracts offered by the IOUs vastly increased the number of cogeneration facilities. The pricing in the standard offer contracts provided incentives to subsidize the industrial power and steam user at the expense of California's electricity customers. In many instances the developer of the electric generator sought out potential industrial users of heat and contracted to sell them cogenerated heat (steam) at prices well below the economic value of that steam, just to qualify under PURPA and receive the prices provided by the QF contract. In some instances the developer created questionable thermal users like skating rinks without skaters, agricultural dryers of products that did not need drying, distilleries of unneeded distilled water, or industrial facilities that simply dumped cogenerated steam through a vent stack when they did not need it. FERC has just issued a NOPR, as part of the implementation of the Energy Policy Act of 2005, to do away with "sham" thermal uses and require true efficiency from QF cogenerators.

Most PURPA cogenerators can be grouped into two basic categories. The first group generates just enough steam to qualify under FERC's PURPA mandated efficiency and operating standards. This type of cogenerator may serve the steam needs of a food processor such as the Calpine King City facility. The second type, sometimes referred to as a thermally matched facility, extracts the maximum amount of heat from the electric generating equipment that is economically feasible.

The overall economic efficiency of the first group is only as good as the efficiency of the electric generator. This is because the value of the amount of heat recovered in the process that is required to satisfy the minimal FERC efficiency is relatively small in comparison with the value of the electric energy generated. The overall thermal efficiency of this group is almost always less than that of a modern combined cycle generator.

The economic efficiency is greater for the second group. This second group is represented exclusively by Enhanced Oil Recovery (EOR) cogeneration facilities. These plants typically are owned by partnerships or directly by oil companies and sell steam to oil producers. Yet, despite their potential efficiency, their contracts are among the highest cost of all the IOUs' procurement. If these cogeneration plants are truly efficient, they do not need special treatment. They especially do not need subsidies, which raise already high utility rates, to extract crude oil when it is trading at $65/barrel.

Given the very broad range of facilities with varying levels of efficiency, air emissions, and system impacts the Commission should not require IOU's to use standard offer contract to purchase electricity from CHP plants delivered at the utilities' avoided costs, as determined by the CPUC in R.04-04-025. Doing so would result in inefficient, environmentally less superior facilities receiving preference, and efficient, clean facilities receiving a "free ride", all at great expense of California IOU customers. There are many efforts underway at the CEC, the CAISO, FERC, and the CPUC all directly aimed at improving wholesale market conditions in California within the next 2 years. In addition, the Energy Policy Act of 2005 includes PURPA reforms that provide efficiencies that will lower costs to IOU customers. So to require utilities to offer standard contracts now will only preempt the more cost effective approach that is just around the corner. Instead, the report should recommend that IOUs negotiate CHP power purchase agreements on a case-by-case basis until such time, in the very near future, when the 2005 Energy Policy Act PURPA reform is implemented in California.

The ongoing CPUC Avoided Cost proceeding is now addressing the appropriate level of energy prices for old cogeneration plants under the standard offer contracts, as well as the appropriate treatment of expiring and new QF contracts under PURPA. The CEC's Draft Report proposes the unjustified support, and the continued subsidization of old cogeneration contracts regardless of their value to the system, their level of efficiency, their environmental status, or their impact on the state's electric rates. This simplistic one-sided position of the cogeneration advocacy groups should not become state policy, and should be clarified in the CEC's Final Report.

NUCLEAR POWER (Chapter 4)

The 2005 IEPR included consideration of the role of nuclear power in California's energy picture. Because the discussion of nuclear power in the Committee Draft Report is brief and highly summarized, it overlooks much of the valuable information presented at the August workshop and contained in the consultant's report prepared by MRW & Associates. PG&E respectfully requests that the Commission modify the draft report in three ways.

First, in order to ensure that the discussion of nuclear power in the IEPR is appropriately balanced, the summary should include facts summarizing the substantial benefits associated with nuclear power in California. There was ample evidence provided of these benefits in the Committee's consultant report and in comments at the public workshop.

Second, the discussion in the draft of the potential for license extension for existing California nuclear facilities is factually inaccurate and should be modified or deleted. The draft erroneously concludes that it is "likely" that the utilities will proceed with license extension applications. There was no evidence introduced in the consultant report or by participants in the public workshop to support such a conclusion. Absent a sound basis, the language in the draft amounts to speculation and should be deleted.

Third, in the final sentence of the nuclear section, the Draft Report recommends that the California Legislature should develop a framework for review of the costs and benefits associated with potential applications by utilities for license extensions. This recommendation for legislative action is unnecessary as 1) no utility in California has decided to proceed with license extension applications; and 2) if such an application is filed in the future, there already exists a comprehensive framework through the Nuclear Regulatory Commission (NRC) for review of the safety, public health, environmental, and technical issues associated with such a project. California would be accorded participant status in such a proceeding. Thus, there is no need for the California Legislature to develop a framework for review. In fact, implementation of a duplicative state process for review of matter within the jurisdiction of the NRC has been found to be unconstitutional.

1) **The Draft Fails to Summarize any of the Substantial Benefits Associated With Nuclear Power.**

The draft report includes only three pages on nuclear issues and summarizes some of the key issues raised in the MRW consultant report and presented at the August 15-16, 2005, workshop. However, the summary fails to reflect any of the substantial benefits associated with nuclear power, as presented in the comments and consultant report. By focusing on challenges associated with nuclear power and ignoring the benefits, the overall tone is unbalanced. PG&E recommends that a few sentences be added to the report to restore an appropriate balance.

PG&E demonstrated in its comments that:

- Nuclear power represents about 23 percent of PG&E's supply portfolio. This significantly reduces dependence on natural gas and is important from an economic and reliability stand-point.

- Diablo Canyon has operated reliably and safely since it commenced operations in the mid 1980s. The plant also provides $640 million in economic benefits to the County of San Luis Obispo and $724 million in economic benefits to the State of California.

- Diablo Canyon has been a reliable source of power, with capacity factors averaging in the ninety percent range after the initial operating cycles.

- Diablo Canyon power is economic. The current fully-loaded cost of power is about $43/MW-hr.

- Diablo Canyon has virtually no impact on air quality. Replacing the output with gas-fired combined cycle generation would increase greenhouse gas emissions by 7 million tons per year.

Chapter 3 of the MRW consultant's report further identifies significant benefits associated with nuclear power. PG&E requests that the draft IEPR be modified to reflect a summary of the benefits of nuclear power.

2) **The Conclusion in the Draft that Nuclear License Extension Applications are "Likely" is Unsupported and Premature.**

The draft report on page 73 states that "Given the high cost of these projects—for example, the $700 million to $800 million for steam generator replacement costs—it is likely that IOU owners will seek to extend operating licenses at the units."

This conclusion that operating license extensions will be sought is based on speculation, not on evidence in the record. PG&E has said that it is proposing to initiate a feasibility study in 2007. The study will take approximately three years to complete. After the study is completed, PG&E will be in position to evaluate license extension. No decision has yet been reached.

The report refers to the large capital expenditures that the utilities are making on the plants and draws the conclusion that plant life extension applications must necessarily follow. In Decision 05-02-052, the California Public Utilities Commission preliminarily concluded that the steam generator replacement project is cost-effective. The Commission performed its own cost-effectiveness analysis to reach this conclusion across several scenarios, all of which assumed that Diablo Canyon Units 1 and 2 would operate only until the end of their current license lives in 2021 and 2025. In the expected case, the Commission concluded, assuming the plant runs through the current license lives, the SGRP will provide a $333 million benefit to ratepayers (on a present value of revenue requirement basis). *See* Decision 05-02-052, page 41 and Findings of Fact 107-111. The economic benefit case for PG&E's steam generator project was premised exclusively on the existing license life for Diablo Canyon. The economic analysis showed that it is cost effective to proceed with the replacements for only the remaining license period. Thus, the projects were not justified based upon an assumption that they would extend the life of the plant.

Similarly, in the final environmental impact report prepared in connection with the Diablo Canyon SGRP, the CPUC concluded that license extension is not a reasonably foreseeable consequence of the SGRP, the impacts of which must be analyzed under the California Environmental Quality Act, because PG&E is only in the preliminary stages of analyzing the feasibility of license extension. The uncertainty of whether PG&E will choose to pursue license extension, along with the uncertainty of whether the Nuclear Regulatory Commission will approve license extension, led the CPUC to conclude that its analysis of the environmental impacts of the SGRP properly focused on the potential environmental impacts of the SGRP through the current expected license lives of Diablo Canyon Units 1 and 2. (Final Environmental Impact Report: Diablo Canyon Power Plant Steam Generator Replacement Project, Aspen Environmental Group, August 2005 at pages 11-21.)

There is no evidence to support a finding that license extension applications are likely and it is inappropriate to make a finding in the IEPR that is contrary to the CPUC's findings on the matter and that would prejudge the feasibility assessment that will not even begin until 2007.

3) The Recommendation in the Draft that the Legislature Should Develop a Framework for Review of Potential License Extension Applications Overlooks the Existing Federal Process for Comprehensive Review. There is no need for Legislative Action.

The draft report recommends that the Legislature should provide a forum for review of issues associated with license extension. On page 73 of the Committee Draft, the Report concludes that it is appropriate for the state to undertake a careful and through review of the costs and benefits of license extensions, and that "California's Legislature should develop a suitable framework for such of review, including the delineation of agency responsibilities, scope of the evaluation, and criteria for assessment."

PG&E believes that this recommendation should be deleted from the report for two reasons. First, it is premature to make such a recommendation. It is unclear if the utilities will even pursue license extension applications. Any such decision is years away as PG&E does not even intend to initiate its feasibility study until 2007. A more appropriate recommendation would be for the CEC to track the issue and update the next IEPR if there have been any developments.

Second, the recommendation in the draft report is unnecessary and potentially misleading. There is no need for the Legislature to develop a framework for review of potential license extension applications as there already exists today a comprehensive process at the NRC to address plant life extension requests. The NRC process includes a comprehensive review of technical issues (10 CFR Part 54) and environmental impacts (10 CFR Part 51) to ensure that the plant may be safely operated during the additional license period. The State may participate in this process. The applicable NRC regulations (10 CFR Part 2) provide California with the opportunity to participate as full party (10 CFR 2.309) or as an interested state (10 CFR 2.315(c)) and raise contentions/questions pertinent to the license extension application.

Under applicable federal law (the Atomic Energy Act (42 USC 2011 et seq.), NRC has been granted the sole and exclusive responsibility for review of these issues. The State cannot conduct its own process or duplicate the review of these issues. The United States Supreme Court in *Pacific Gas and Electric Company v. State Energy Resources Conservation & Development Commission,* 461 US 190 (1083) made this clear when it held that any state effort to duplicate the NRC's process for the licensing and operation of nuclear power plants would be preempted by Federal law.

For this reason, it is not necessary to suggest that the Legislature should provide a separate, duplicate process for review. A process now exists and California can fully participate without any further action by the California Legislature.

PG&E suggests that the recommendation in the draft report for legislative action be removed on the ground that such a recommendation is premature and unnecessary given the existing comprehensive federal review process.

NATURAL GAS PRICE FORECAST (Chapter 7)

At the October 7, 2005, IEPR hearing on Chapter 7 of the Committee's Draft Report, ("The Challenges and Possibilities of Natural Gas"), PG&E provided testimony on the staff's natural gas price forecast. PG&E noted that staff's forecast of gas prices at Henry Hub for 5-15 years from now is in the same range as those provided by various consultants. PG&E has no objection to that part of staff's forecast.

PG&E also noted, however, that staff's forecast of price differences ("basis") between California and Henry Hub greatly exceeds both forward prices and the historical basis. For example, in the staff's forecast for 2005, gas at the PG&E Citygate costs $2.25/MMBtu more than at Henry Hub. For the first eight months of 2005, before Hurricane Katrina disrupted gas markets, gas at PG&E Citygate actually cost $0.45/MMBtu less than at Henry Hub.[1]

Some of PG&E's concerns about staff's modeling may easily be addressed. For example, staff's modeling omits the existing pipeline between Opal (in western Wyoming) and Stanfield (in Oregon, where it interconnects with pipelines leading to California). Staff's modeling includes a pipeline that does not exist, specifically, a connection from gas supplies in British Columbia directly to central Idaho.

PG&E's primary concern, however, may not be easily addressed. Staff's assumptions on the cost of gas transmission are significantly higher than those of the National Petroleum Council (NPC). Staff's assumptions drive up gas prices in consuming regions, such as California, relative to gas prices in supply basins, far beyond recorded data and market forward projections. (Numerical examples are provided in the Appendix.) Both staff and the NPC use the same modeling software: MarketBuilder. Staff has the NPC database, and has extracted gas-supply curves from it. Unfortunately, extracting NPC gas-transmission assumptions for input to staff's model would be a lengthy process because (1) staff uses a different pipeline geography and different naming conventions and (2) both staff's and NPC's databases contain several hundred pipeline segments. In the terms Commissioner Geesman used at the December 16, 2004, workshop, both of these models are "ocean liners," not "speedboats."

In view of the IEPR schedule, PG&E recommends that the Commission adopt staff's forecast of gas prices at Henry Hub for 5-15 years from now, along with a gas-price difference between Henry Hub and California of zero. A basis of zero seems reasonable; gas has been cheaper at

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[1] After Hurricane Katrina hit, unusual pipeline shutdowns caused gas prices at PG&E Citygate to fall even further below prices at Henry Hub. In September 2005, gas at PG&E Citygate cost $2.00/MMBtu less than at Henry Hub.

PG&E the Citygate than at Henry Hub in recent years, and market quotes suggest that this condition will persist indefinitely.

In addition, PG&E recommends that market prices (e.g., NYMEX futures) be used for the first few years of a gas-price forecast, rather than results from staff's or any other model. Models typically assume perfect foresight and economically optimal behavior, rather than the "boom and bust" that frequently occur in commodity markets.

PG&E also notes that Staff's modeling input prohibits future LNG terminals on the U.S. West Coast, no matter how economic they may be, by assuming a regasification charge of $50/MMBtu. Staff uses a different, realistic charge for other coastlines, including Baja California. Staff's desire to avoid "picking winners" among the current LNG proposals for Southern California and Oregon is understandable. However, staff's modeling drives up the gas-price forecasts for California points, and is inconsistent with staff's use of "generic" power-plant additions in its electricity analysis.

If only a model-based forecast is acceptable, PG&E recommends setting the shrinkage, O&M, and Elastic Supply Slope variables for pipelines in staff's input to 100 percent, zero, and 0.01, respectively. These values will reduce the excessive gas-transportation charges in staff's MarketBuilder results. This suggestion may only serve as a "band-aid," a temporary solution, because the remaining time in the IEPR process would not allow individual examination of each of the 348 pipeline segments in staff's input.

To further assist the Commission, and particularly Commission staff, we have provided more detail in a technical appendix located after the conclusion of our comments.

GLOBAL CLIMATE CHANGE AND A GREENHOUSE GAS STANDARD (Chapter 9)

PG&E agrees with statements made in Chapter 9 of the IEPR that "climate change is a worldwide phenomenon that has significant implications for all sectors of the state's economy and natural resources." PG&E recognizes that the power sector is one of the largest contributors nationwide to increasing atmospheric concentrations of greenhouse gases and, as such, has an important role in mitigating or reducing these emissions. In California, however, as Figure 19 indicates, the power sector is the third largest identifiable contributor of greenhouse gases in the state (contributing 20 percent to the state's total greenhouse gas emissions), with emissions split evenly between in-state and out-of-state generation. For context, the U.S. power sector accounts for approximately 35 percent of total U.S. emissions. The fact that the power sector contributes only 20 percent to California's total is a testament to the effectiveness of policies and programs that have been pursued by the state and the investor-owned utility sector to mitigate emissions from traditional generating sources, encourage energy efficiency, and invest in renewable and alternative power generation technologies. For example, PG&E's long term procurement plan includes no coal, other than the QF resource currently in our delivery mix, which accounts for approximately three percent of our total delivered retail electricity sales.

While the investor-owned utility sector has made significant contributions to helping the state responsibly address greenhouse gas emissions, we understand that additional activities could be pursued. Given the global nature of the problem, it is PG&E's strong preference that greenhouse gas regulation occur at a national level, be market-based, and either encompass or provide for the opportunity for multiple sectors to participate in a program. However, we also recognize California feels an obligation to address this important issue and assume a leadership role on the matter. We, therefore, are committed to working with California's climate change stakeholders to develop a program that (1) leverages existing policies, programs, initiatives, and investments that mitigate climate change; (2) addresses concerns about emissions flowing out-of-state or being transferred from investor-owned utilities to municipal utilities; and (3) is flexible enough to fit into any future regional or national program that may emerge.

Performance Standards

Overview of Discussions Concerning Performance Standards

PG&E agrees with, and is supportive of, many of the statements and issues addressed in Chapter 9 of the Draft IEPR. However, issues impacting climate change and future greenhouse gas regulation are not embodied solely in Chapter 9. For example in Chapter 4, and in subsequent correspondence, issues and concepts have been raised that not only will impact overall greenhouse gas emissions associated with the power sector, but that could also have significant implications for power costs, generation investment, and reliability going forward. In particular, on page 71 of the Draft IEPR, in connection with a discussion on encouraging/leveraging investment in clean coal technologies, the following was proposed:

> Without burdening interstate commerce, or discriminating against particular technologies or fuels, the state should specify a GHG performance standard to be applied to all utility procurement, both in-state and out-of-state, both coal and non-coal. While more specific recommendations must await the January 2006 report of Governor Schwarzenegger's Climate Action Team, the Energy Commission recommends that any GHG performance standard for utility procurement be set no lower than levels achieved by a new combined-cycle natural gas turbine. Additional consideration is needed before determining what role, if any, GHG emission offsets should play in complying with such a performance standard.

The concept was again raised and discussed by Chairman Desmond in his memorandum to Commissioners Geesman and Boyd (dated September 22):

> Prior to adoption of mandatory limits California should avoid "more long-term investments (exceeding 3 – 5 years in duration) in baseload power plants with emissions per megawatt-hour of greenhouse gases and criteria air pollutants exceeding those of a combined cycle natural gas turbine.
>
> Chairman Desmond then goes on to ask for comment on "whether power plant sponsors should be permitted to use emissions offsets…

Finally, this concept was most recently discussed and promoted at the CPUC, where, on October 6, 2005, the CPUC endorsed the Draft IEPR's inclusion of a performance standard for both greenhouse gas emissions and criteria pollutants and voted to order staff to investigate how to integrate a performance standard into the CPUC's existing policies regarding GHG emissions, including the environmental adder and the procurement incentives framework proceeding.

PG&E's Position on Performance Standards

PG&E has interpreted California's energy policy over the past several years to be based on the following principles: (1) pursue supply resource options that are least cost and best fit, (2) make that portfolio as clean as possible. Performance standards can help to achieve those objectives; however, they must be applied correctly and recognize limitations from a contractual, an administrative, and a technology availability standpoint, while at the same time support and be coordinated with existing policies and programs.

PG&E believes that assuming *arguendo* that state-level rather than national standards are pursued, a greenhouse gas performance standard may be an effective and cost-efficient means of mitigating greenhouse gas emissions if it is: (1) applied on a portfolio-wide basis, (2) applied to all load-serving entities in the state (regardless of ownership structure) in a consistent manner, and (3) integrated into the overall multiple-source program being developed by the Climate Action Team to meet the Governor's targets.

Establishing target emission standards (on a pound per megawatt-hour basis) that are applied portfolio-wide will allow load serving entities to manage resources in a way that optimizes their supply portfolio at least cost. For example, setting target emission standards portfolio-wide, as opposed to on a contract-by-contact basis, will allow the portfolio manager to determine the mix of resources that will best meet customers' needs reliably and cost-effectively, whether it be through additional investment in energy efficiency, additional purchases of renewable generation, investment in new combined cycle gas turbines, or investment in clean coal technology (e.g. IGCC). And, more than likely, in order to diversify risk, a portfolio manager will create a supply portfolio that draws from each of these resource options. Setting performance standards in this manner, therefore, not only results in similar emission reductions, but it also is well-aligned with and supportive of the Energy Action Plan's preferred loading order, avoids presupposing the right mix of technologies and resources today to meet needs tomorrow, and allows for future adjustment of standards as technologies improve.

The issue of which entities are affected by this standard is critical. If the standard is implemented solely through the CPUC, which does not have the ability to apply the standard to municipal utilities, then not only will inequities arise, but there is a high probability that these emissions will merely be shifted from investor-owned utilities to municipal utilities by allowing higher-emitting municipal utilities to avoid costs and offer a price advantage over investor-owned utilities, attracting load away from the investor-owned utilities and negating any perceived benefits. In addition, emissions standards should be set in a way that does not discriminate against entities that have already taken significant steps to mitigate greenhouse gas emissions; i.e., a consistent set of emissions standards should be established for all entities, rather than separate standards for individual entities.

Performance standards in and of themselves will not guarantee overall emissions reductions. In isolation, a performance standard is an effective means of reducing the greenhouse gas intensity of power sector emissions, but not necessarily of reducing total emissions. Performance standards would therefore be better considered as part of a suite of options the Climate Action Team reviews as it creates a plan to meet the Governor’s emissions’ targets. Performance standards developed and applied outside of the overall Climate Action Team process run the risk of creating unintended consequences.

With regard to some of the specifics being discussed in the Draft IEPR, Chairman Desmond’s Memorandum, and at the CPUC, PG&E has the following concerns and questions:

- It is our understanding the performance standard would apply on a contract-by-contract basis to baseload facilities and only to contracts that exceed 3 to 5 years in length. This approach raises a number of issues that should be considered and resolved before such a standard is imposed. Specifically:

    - How would the standard apply if the facility can sell to multiple customers, some of whom would be willing to pay the premium and some who would not be willing to pay the premium? Would this mean that California utilities are the customers of first resort because they are willing to pay the premium or that they are the customers of last resort because the complexities associated with meeting the California requirements aren't worth the premium given other customers that are willing to take a more standard product?

    - Who would decide whether the performance standard incorporated in the contract is met? Would the utility-customer be expected to file a breach of contract action if it concluded the standard wasn’t met? What would the measure of damages be if the standard wasn’t met? Would the contract be terminated regardless of whether the energy generated by the facility is needed to meet demand?

  - Would the utility be required in the contract to specify that the megawatts generated by the facility be delivered physically to the purchasing utility? If so, where does that delivery need to take place?

  - With regard to the question of which facilities would be covered by the standard, although it appears that currently only baseload capacity is being contemplated, CPUC Commissioner Grueneich indicated that applying such a standard to peaking facilities should be investigated. We are very concerned about implications setting such a contract-specific standard could have on electric system reliability.

- Second, it appears that the performance standard will apply to more than just greenhouse gases.

  - Both Chairman Desmond and the CPUC suggest that a performance standard should be set for criteria pollutants as well. If this is the case, we question whether or not even clean coal technologies, as described in the Draft IEPR, would be able to meet the mercury emission levels that would be set, given the current state of technology. Similarly, for CO_2, while PG&E agrees that future investments in clean coal should include, or have the capability of including, carbon capture technology, at this juncture, there are no existing facilities that meet this standard in the Western Interconnection and there are few facilities that are contemplating investment in IGCC with carbon capture. If current technology, or the existing asset base, cannot meet these standards, then the state is making a policy that the state's load serving entities will not be able to enter into contracts for electricity generated by coal for the foreseeable future.

Our point is not to suggest that California not adopt performance standards. It is to suggest that any such standards must be carefully considered and properly implemented. PG&E remains very interested in discussing these issues to make sure that any performance standards adopted can be successfully implemented to produce the desired results.

Greenhouse Gas Emissions Offsets

With regard to the specific question posed by the Draft IEPR and in Chairman Desmond's September 22, 2005, Memorandum regarding the use of offsets in concert with performance standards, it is difficult to address the issue. Because there are outstanding questions with regard to how the performance standard will be implemented, it is premature to discuss the feasibility and impacts of using offsets at this time, except to say that offsets in the form of non-emitting generation and energy efficiency could be captured in a program that incorporated performance standards applied on a portfolio-wide basis. This is an important point because applying the standard portfolio-wide will help to integrate the existing investment in, and policies towards, energy efficiency and renewable generation and ensure that they are being incorporated into an overall greenhouse gas reduction strategy.

With regard to the concept of offsets in general, PG&E is supportive of using offsets – or off-sector reductions – in a greenhouse gas regulatory program. Because climate change is a global issue and not a local air quality issue, reducing a ton of CO_2 by converting a gasoline-powered fleet to natural gas or hybrid vehicles is as beneficial as reducing a ton of CO_2 from a power plant. The issue with regard to offsets is not whether or not they make a contribution to mitigating greenhouse gas emissions, the issue is how to account for, track, and audit these reductions to ensure that they are credible. The California Climate Action Registry is working to develop standards and protocol for accounting for and registering emission reductions across sectors and we believe that no determination should be made on the use of offsets in association with the proposed performance standards until the Registry has developed and approved its protocol.

PG&E looks forward to working with other climate change stakeholders, including the CEC and the PUC, to develop and implement cost-effective strategies that both address greenhouse gas emissions and meet the state's other energy policy objectives.

TRANSMISSION CHALLENGES AND RENEWABLE RESOURCES (Chapters 5 & 6)

Draft Comments on the CEC: PG&E comments in the section below refer to Chapters 5 & 6 of the Committee Draft Report and to the companion IEPR Strategic Transmission Investment Plan

1. PG&E recommends that the CEC take a more western-wide strategic view, beyond a California-specific focus.

   PG&E appreciates the Commission's effort to further the development of transmission infrastructure. Because transmission to gain access to resources is inevitably driven by the locations, characteristics, and size of existing and new resources, and because activities in one part of the Western Interconnection may affect other parts, sometime significantly, it is important to take a broad view when planning for transmission. The CEC should consider information on resources located not only throughout California but also the Western Interconnected System covered by the Western Electricity Coordinating Council (WECC). This is important because transmission needed to accommodate resources in one cluster could exacerbate – or eliminate – the need for transmission upgrades to accommodate resources in other clusters. For example, if it is determined that providing access to renewable resources in the Pacific Northwest would provide benefits to California customers, which exceed costs of the associated transmission upgrades, then such transmission upgrades should be built towards the Pacific Northwest. In doing so, given that the California load level remains the same regardless of the location of the resource, less transmission infrastructure would be required to gain access to resources in the Southwest. Therefore, in this example, some transmission upgrades built towards the Southwest may be unnecessary. This example can be applied to any parts in WECC. So, to take full advantage of the resource information available, the Commission should look beyond California when investigating the strategic transmission investment.

2. PG&E recommends that the CEC staff assist in planning, especially for renewables development, by conducting scenario analysis for stakeholder group evaluation.

   Because strategic transmission investments are primarily driven by the availability of resources, to conduct transmission planning studies in a more efficient way would be to start by developing resource scenarios based on the likelihood of development of the resources. The CEC has developed an abundance of information on the type, amount, location, and timing of the renewable resources that would be technically and economically available. This information can be augmented by the market information and results from the RPS solicitations. All of this information may be used to develop several likely renewable resource scenarios that can be screened by the ISO and stakeholder groups. Each scenario should cover likely renewable resource developments in all areas in California as well as those covered by WECC.

   This information may then be used by the ISO in a stakeholder process to determine which transmission corridor or corridors should be upgraded to produce the greatest economic benefits for customers in light of RPS goals. Priority should be given to upgrades that provide the maximum benefit in terms of ensuring the success of the RPS program while mitigating ratepayer risk to the greatest extent possible. For example, transmission projects that would facilitate the development of renewable resource areas that have a high likelihood of succeeding in the near-term should be favored over upgrades aimed at resource areas in which generation development is more speculative, or might not occur for many years. Upgrades to transmission corridors that would be needed under more than one scenario of resource development should be given higher priority than upgrades to transmission corridors identified in fewer scenarios. This initial prioritization would also mitigate the ratepayer risk of potentially wasting millions of dollars on transmission upgrades if the renewable resources in a single area do not fully develop or develop later than expected.

In all events, information and results from RPS processes to date must be fully considered. This is a critical step in the process because theoretical development potential may not necessarily reflect the development that is actually occurring through RPS processes. However, by carefully checking projections of development potential against actual market results, the parties will have a sound basis for assessing which transmission upgrades are best for California.

A WECC-wide approach informed by market information and results may reveal that the best solution is to invest in a number of transmission-constrained areas, or in large projects capable of serving multiple purposes, rather than investing huge sums in hopes that a single area will develop to its full potential and overcome any integration, financing, and siting challenges it may face. Investing smaller amounts in a number of resource areas and/or larger amounts to construct transmission projects that provide multiple benefits avoids putting all of California's eggs in one basket, and may also foster increased competition among renewable developers, thereby further reducing costs to ratepayers. Finally, a comprehensive WECC-wide approach seems more likely to result in identification of transmission projects that can be approved by the ISO for addition to the grid and funded by the IOUs under existing regulatory requirements.

For example, PG&E's 2005 Transmission Ranking Cost Report shows that a number of network facilities requiring upgrades to accommodate potential new generation are common to several clusters depending on the levels of generation added. PG&E's studies in conjunction with the Tehachapi Collaborative Study Group (TCSG) also identified transmission facilities between Midway and Los Banos that would need to be upgraded. These common network facilities that are identified as limiting facilities would provide some insight into those transmission paths where the risk to customers (of installing unnecessary upgrades) could be reduced:

- Cortina – Vaca-Dixon 230 kV line
- Shiloh – Contra Costa 230 kV line
- Table Mountain – Vaca-Dixon 500 kV line
- Wesley – Los Banos 230 kV line
- Tesla – Los Banos 500 kV line
- Midway – Gates and Midway – Los Banos 500 kV lines

Information from the Northwest Transmission Assessment Committee (NTAC) shows large amounts renewable resources outside California. NTAC is investigating economic transmission expansion options to increase power transfer into markets as far south as California (see Figures 1 – 3). Some of the NTAC transmission options (Options 2, 3, 4 and 5) envision transmission additions within Northern California. These options can therefore also be used to foster renewable resource development in Northern California and enable deliveries of these resources to load centers in Northern and Central California and beyond. For instance, options that envision a 500 kV line between Malin/Captain Jack and Tesla Substations can be modified and extended to also help access resources within the northern part of the PG&E system and deliver to load centers in the South San Francisco Bay Area.

Options that increase transfer capability northward from PG&E's Midway Substation would allow PG&E to gain access to all potential types of renewable energy in Southern California in addition to the potential wind resources in the Tehachapi Area. These southern options may be installed in stages depending on the expected renewable resource development in Southern California and the Desert Southwest. For example, installing a Midway – Gregg 500 kV line could increase PG&E's South to North transfer capability from Midway during offpeak by about 1,100 MW. It could also allow increased utilization of existing pumping capability at Helms Pumped Storage Plant, and could increase reliability to the Great Fresno Area during on peak conditions.

The question then goes back to the amount and timing of the technically feasible potential renewable resources that would develop in one area relative to other areas. Methods similar to the ones being used in the Commission's Strategic Value Analysis could provide insight into development of scenarios. Scenarios from such analysis, augmented by information from the RPS solicitations, would form the foundation on which a strategic transmission corridor may be investigated and planned.

3. PG&E recommends that the CPUC, CEC, and ISO continue to work toward a single, end-to-end transmission planning process and avoid complicating the process by introducing new and duplicative steps.

4. PG&E cautions the CEC about creating a new set of data requirements in the 2006 IEPR update or in the 2007 IEPR proceeding by requiring bus bar level data for disaggregated load forecasts. PG&E recognizes that this recommendation is based on a request from the California Independent System Operator (CAISO).

   PG&E understands the importance of accurate load forecasts disaggregated down to the bus bar level for transmission planning. In fact, PG&E already provides the CAISO with load information down to the bus bar level. As such, PG&E is concerned that the CEC may be unintentionally creating a duplicative process for PTOs, such as PG&E, that already provide the information required. PG&E respectfully urges the Commission to reconsider this recommendation and to allow flexibility for processes that already exist and are functioning satisfactorily.

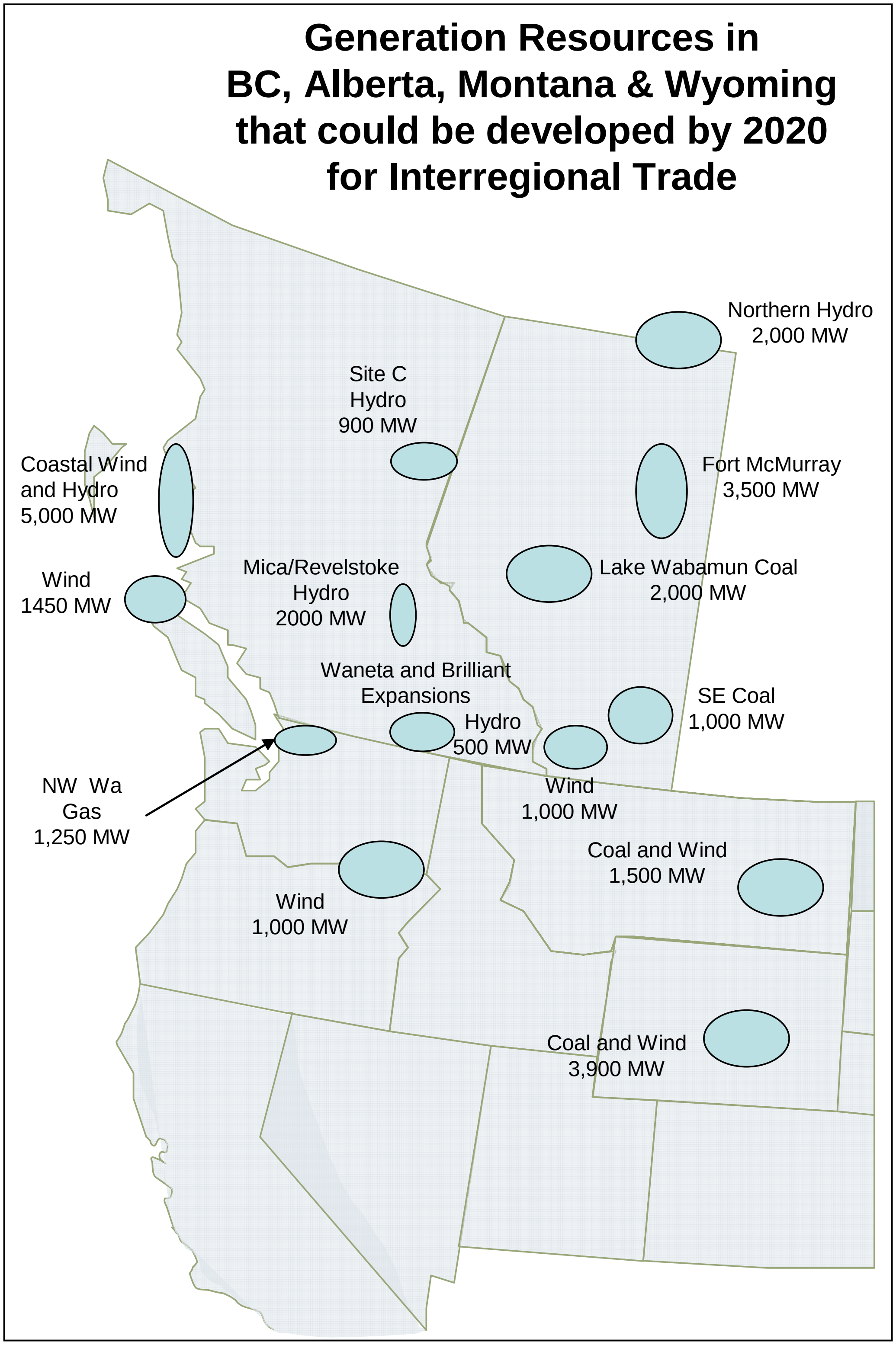

Figure 1: Potential Generation Resources Within the NTAC Study Area

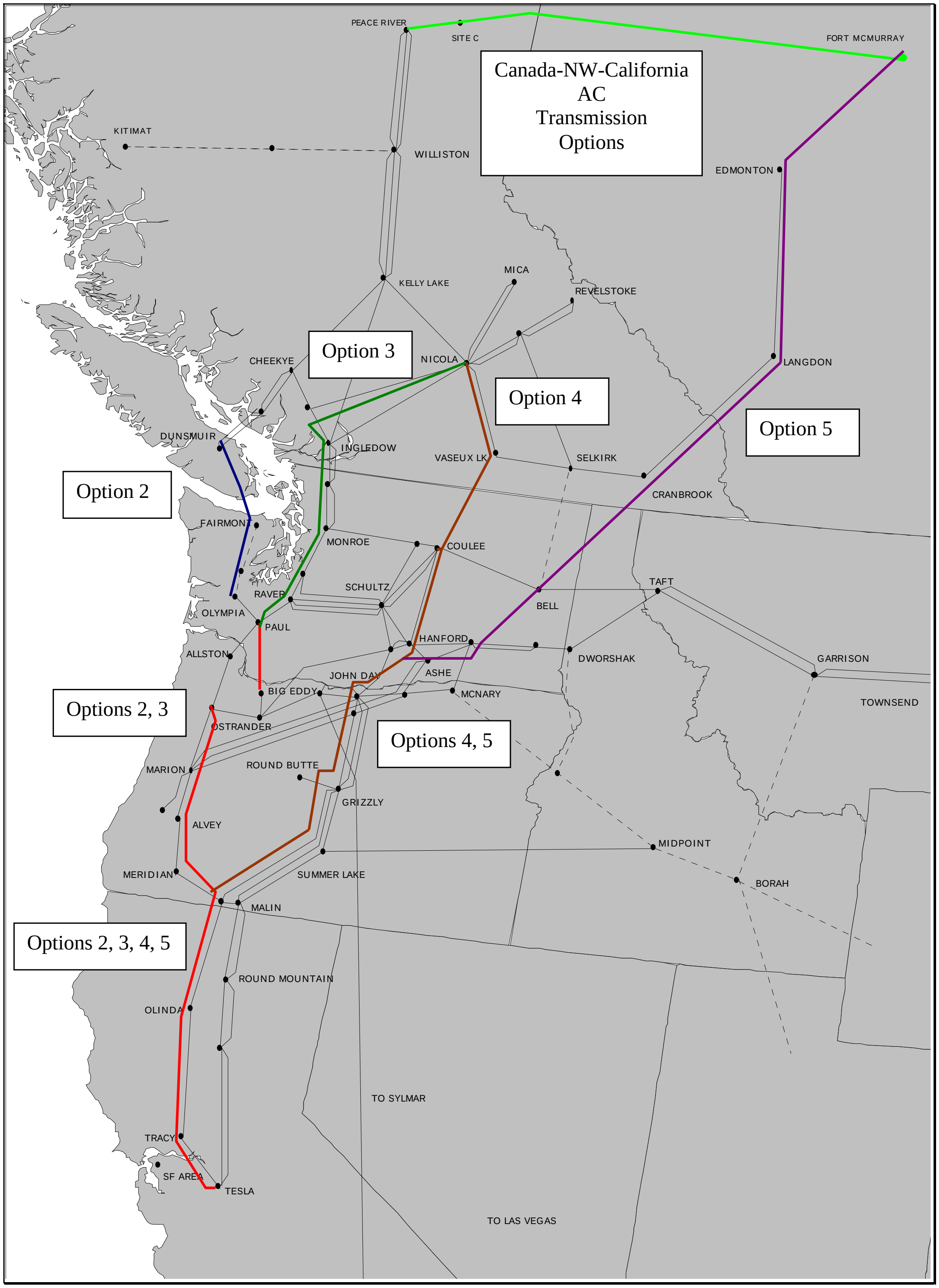

Figure 2: NTAC AC Transmission Options

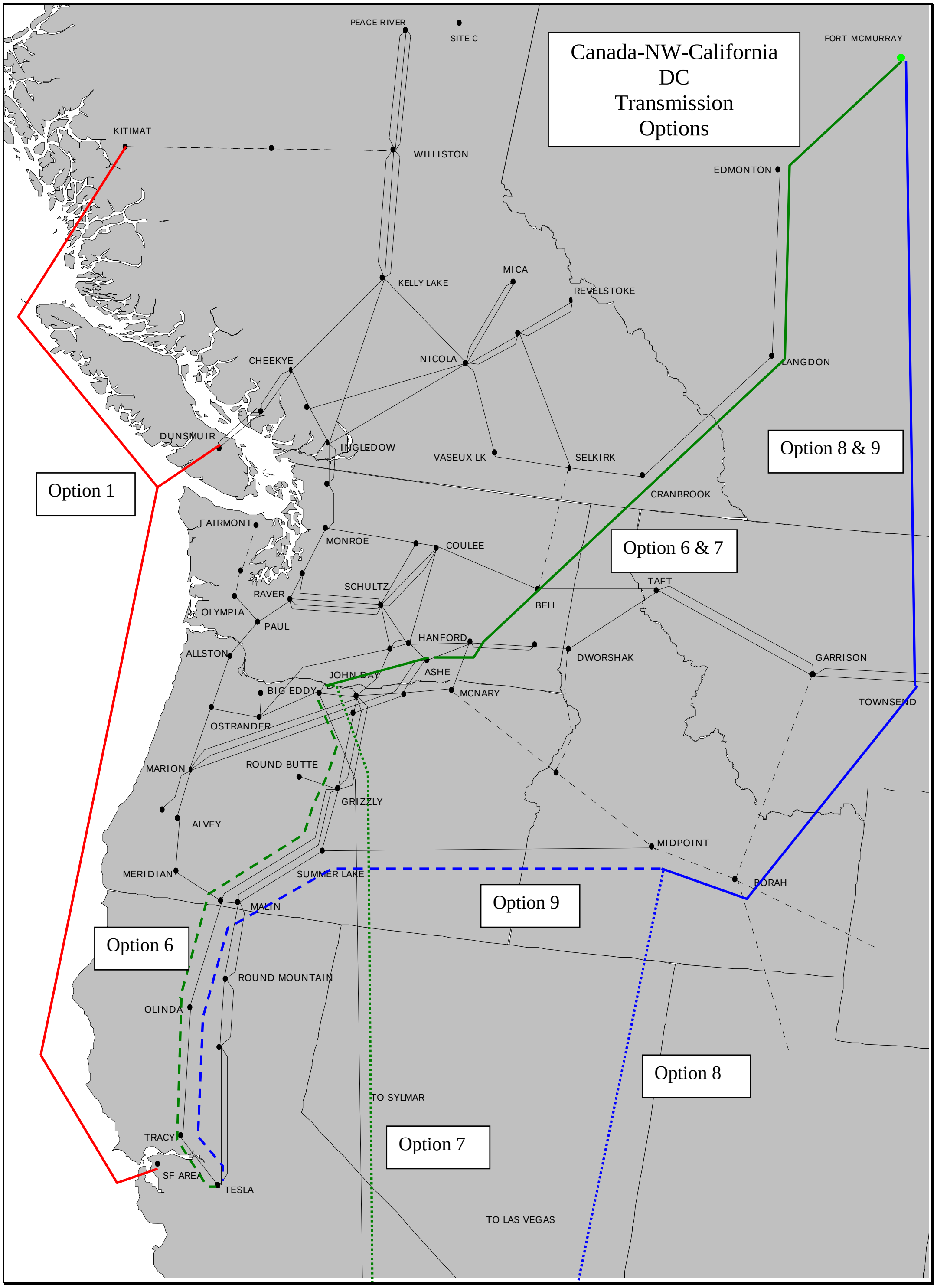

Figure 3: NTAC DC Transmission Options

TRANSBAY CABLE PROJECT

At the September 23, 2005, Committee hearing on the Committee Draft 2005 Strategic Transmission Investment Plan, Commissioner Geesman requested that PG&E provide a written statement explaining its position on the TransBay Cable Project (the "TBC Project") in our comments on the Committee Draft Report.

The TBC Project is a joint project between TransBay Cable LLC and the City of Pittsburg involving the construction of a new, approximately 59-mile long DC cable between PG&E's existing Pittsburg and Potrero substations, the majority of which would be installed in the San Francisco Bay; two new converter stations, one to be located in Pittsburg and the other in San Francisco; and related facilities.

The TBC Project was considered as part of an ISO-led stakeholder study of the long-term transmission needs of the San Francisco and the northern San Mateo County area. PG&E agrees with the ISO, TransBay Cable LLC, and other stakeholders that a new 230 kV transmission line from the East Bay to San Francisco is needed to address long-term transmission needs in the San Francisco and northern San Mateo County areas.

During the stakeholder process, PG&E proposed the Moraga-Potrero 230 kV AC project as its preferred alternative to meet the demonstrated need. However, on September 8, 2005, the California ISO Board of Governors instead approved the TBC Project as "the preferred long-term transmission alternative (without regard to routing)" and conditioned its approval on the proponent's ability to obtain all "necessary permits and state easements by April 2007."

In light of the ISO Board's decision to approve the TBC Project, and as required by our tariff, PG&E will continue to work with the proponent TransBay Cable LLC to complete the ISO-required studies necessary to effect the interconnection of the TBC Project to the ISO-controlled grid at PG&E's Pittsburg and Potrero substations.

APPENDIX - Technical Comments on Gas Modeling

PG&E's comments deal with staff's representation of gas pipelines in its input for the MarketBuilder software. PG&E regrets that, by necessity, PG&E's comments are extremely narrow, technical comments. PG&E has attempted to add enough context such that non-modelers can understand the changes PG&E recommends. Note that making the changes recommended by PG&E will not necessarily yield a better price forecast, for two reasons:

- PG&E's recommended changes are not comprehensive due to lack of time. The staff's input to the MarketBuilder software contains 348 individual pipeline segments. Evaluating all of them is a lengthy process. This evaluation is particularly difficult because, though staff, PG&E, and the National Petroleum Council all use the MarketBuilder software, staff uses a pipeline topology and naming conventions differing from the set used by PG&E and the NPC.
- PG&E's recommended changes might reveal some other problems in the modeling. In particular, PG&E notes that a representative of TransCanada Pipeline expressed concern about the low gas production from Alberta in staff's modeling. Gas production may be low in the model because gas transmission charges in staff's modeling are too high, or staff's gas-supply curves are too costly, or some combination. Reducing the gas transmission charges, as PG&E recommends, may or may not highlight questions about the gas-supply curves.

Consequently, PG&E will not necessarily endorse whatever result arises in response to PG&E's recommendations.

1. Gas Transmission Charges

PG&E believes that Staff's gas transmission charges are too high, leading to artificially high basis. ("Basis" is the price difference between two trading hubs). The table below shows actual basis between various points for January through August 2005, and staff's forecasts for 2005.

Trading Hubs	Actual Basis: January-August 2005 ($/MMBtu)	Staff's Forecasted Basis: 2005 ($/MMBtu)
PG&E Citygate minus AECO (Alberta)	$0.67	$1.27
PG&E Citygate minus SoCal Topock	$0.27	$0.83
PG&E Citygate minus Henry Hub	-$0.45	$2.25
PG&E Citygate minus Opal	$0.53	$1.13

Note the minus sign: For the first 8 months of 2005, before Hurricane Katrina disrupted gas markets, gas was cheaper at PG&E Citygate than at Henry Hub, opposite of staff's forecast that it would be more expensive.

As an illustration of pipeline charges, PG&E selected the path from Alberta to PG&E Citygate. To make sense of PG&E's comments, it is unfortunately necessary to dive into the details of pipeline charges in MarketBuilder. The input data for each gas pipeline segment in MarketBuilder include the following:

- Shrinkage (some gas is used as compressor fuel, so gas output at Point B is slightly less than gas input at Point A)
- Variable O&M (in $/MMBtu)
- Elastic Supply Slope or ESS, which describes how the price between Point A and Point B increases with demand for gas transmission, up to the point at which scarcity pricing begins.

The inputs used by staff for the Alberta-PG&E Citygate path are as follows:

Row	Region	Name	Shrinkage	O&M	ESS
1	Rg2-02a:Alberta Wellhead	T:Alberta=>S. Alberta	0.980	0.043	0.078
2	Rg1-13b:Canadian Imports (PNW)	T:PGT Exp=>Stanfield	0.985	0.033	0.078
3	Rg1-13b:Canadian Imports (PNW)	T:Hub=>Hub Trans	0.990	0.000	0.010
4	Rg1-13b:Canadian Imports (PNW)	T:PGT Exp/PNW=>Malin	0.995	0.026	0.078
5	Rg1-13a:Canadian Imports (Calif)	T:Line 400/401=>N. Calif	0.990	0.070	0.078
6	Rg1-24a:No. California Supply	T:NorCal Supply=>PG&E	0.985	0.000	0.010
7	Rg1-26b: PG&E PGen	T: Hub=>Hub Trans	0.999	0.040	0.010
	Total		0.926	0.212	0.342

Staff's input drives up the gas price at PG&E Citygate by 7.4% due to shrinkage because its effect is multiplicative.[2] Staff's input drives up the gas price at PG&E Citygate by $0.212/MMBtu due to O&M. In addition, the Elastic Supply Slopes, which sum to 0.342, drive up the gas price by an amount that depends on the capacity and flow on each of the 7 pipeline segments in Staff's input. The end result of Staff's input is that the PG&E Citygate price in 2005 exceeds the price in Alberta by 41%. For the first 8 months of 2005, the PG&E Citygate price actually exceeded the Alberta price by 14%.

The inputs used by NPC (and PG&E) for the Alberta to PG&E Citygate path are as follows:

Row	Region	Name	Shrinkage	O&M	ESS
1	Supply: Alberta Pipes	P: ANG & Foothills	0.993	0.015	0.010
2	Supply: Canada Imports	P: PGT-Kingsgate to Stanfield	0.991	0.025	0.020
3	Demand: PNW	P: PGT Stan-Malin	0.991	0.015	0.015
4	Demand: NoCal	P: Redwood On	0.998	0.013	0.025
	Total		0.973	0.068	0.070

Note that the NPC uses only 4 pipeline segments, rather than 7 in staff's input, and that the highest ESS in the NPC input is much lower than in the staff's input. The NPC input drives up the gas price at PG&E Citygate by 2.7% due to shrinkage and by $0.068/MMBtu due to O&M. In addition, the Elastic Supply Slopes, which sum to 0.070, drive up the gas price by an amount that depends on the capacity and flow on each of the 4 pipeline segments in NPC's input. The end result of NPC's input is that the PG&E Citygate price in 2005 exceeds the price in Alberta by 14%, which happens to equal the observed value for the first 8 months of 2005.

2. Gas Pipeline Topology

PG&E has not attempted a comprehensive review of the 348 gas pipelines in staff's input to MarketBuilder, and has only a few comments. PG&E does not believe that changing staff's input in response to these comments would be sufficient to eliminate the high gas-transmission costs in staff's modeling—they are merely a start.

[2]For any amount of gas entering the pipeline in Alberta, according to Staff's inputs the amount reaching "PGen" (power generators in Northern California) is diminished by multiplying the seven Shrinkage inputs (0.980*0.985*0.990*0.995*0.990*0.985*0.995 = 0.926, meaning that 7.4% of the gas entering the pipeline is consumed as compressor fuel en route to Northern California.

- PG&E does not understand the purpose of certain pipelines in the model, such as T:Hub=>Hub Trans, which appears several times in staff's input (for example, it appears twice in the path from Alberta to PG&E Citygate, as noted in Rows 3 and 7 in the table above). Deleting these segments would reduce the run time for the MarketBuilder model and possibly eliminate unnecessary gas-transportation charges.
- In Rg1-26a, for pipeline T: PGen BB Trans PG&E suggests setting O&M to 0.05, shrinkage to zero, and ESS to 0.001. For pipeline T:PGen LT Trans PG&E suggests setting O&M to 0.19, shrinkage to zero, and ESS to 0.001.
- In Rg1-13a:Canadian Imports (Calif), the total capacity of three segments, namely T: Line 400=>PG&E, T:Line 400/401=>N. Calif, and T:PG&E Exp=>S. Calif (Line 401), should equal 2021 BCF/d, or 0.737 TCF/yr. We suggest leaving the capacity of T: Line 400=>PG&E at 600 MMCF/d (0.219 TCF/yr), and increasing the capacity of T:Line 400/401=>N. Calif to 0.5 TCF/yr.
- In Rg1-24a, pipe T:NorCal Supply=>PG&E seems unnecessary.
- It appears that the pipeline T:PG&E Baja=>NorCal Supply is intended to represent PG&E's Baja-On service. PG&E suggests setting its ESS to the tariff rate of $0.33/MMBtu divided by $6 gas, or 0.055, eliminating the O&M charge, and setting shrinkage to 0.99. In staff's input, the Baja-On rate appears to be charged twice. To eliminate double-charging for gas from the Southwest, we suggest setting the O&M, shrinkage, and ESS for pipeline T: Topock/Line 300 to zero, 100%, and 0.001, respectively. We suggest the same changes for the pipeline T: Daggett=>NorCal, in order to eliminate double-charging for Rockies gas.
- In Rg1-13b, pipes T:PGT Exp/PNW=>Malin and T:Hub=>Hub Trans seem to be double-charging the PGT rate from Stanfield to Malin. For the latter pipe, we suggest setting the O&M, shrinkage, and ESS to zero, 100%, and 0.001, respectively.
- In Rg1-25a:SoCalGas Company, the hub H:SOUTHERN CAL. GAS CO. Hub (Rg1-25a) seems equivalent to a SoCalTopock price. The pipeline T:PGen Trans may warrant scrutiny.
- In Rg1-23a:So. California Supply, the pipe T:SoCalGas Co. Trans seems unnecessary.
- In Rg1-07c:Permian (Havasu Alloc),the LNG may connect to the wrong place. We suggest deleting all costs on T:Hub=>Hub between H:El Paso S Alloc II and H: BLYTHE/EHRENBERG (Rg1-07c). We also suggest deleting T:Blythe=>So. Calif because the pipeline charges on that path at a different pipe farther on.
- In Rg1-04d, the pipeline T:Rockies=>KRiver captures all of the full tariff rate for Kern River, which has postage-stamp rates. We suggest deleting all costs and shrinkage associated with the three downstream pipes T:Kern River=>Utah, T:Kern River=>SW Desert, and T:Kern River=>Calif.
- The pipe T:Rockies=>PNW (NWPL) goes from Opal to the central-Idaho connection to Reno on Paiute Pipeline. The capacity should be set at 0.245 TCF/yr. Shrinkage should be set at 0.99. A pipe segment with virtually zero cost should be inserted between central-Idaho and Stanfield, and the pipe from Opal to PacNW Citygate should be deleted.
- For T:BC=>Sumas (WestCoast) PG&E suggests setting capacity at 1.2 BCF/d.
- For T:Sumas=>PNW (NWPL), PG&E suggests changing the delivery point from H:BRITISH COLUMBIA/PNW Hub (Rg1-15b), which would have gas flowing backwards to where it came from, to H:PNW (WASH/ORE) CityGate Hub (Rg1-33b).